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June 13, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, Massachusetts 02110

Re: D.T.E. 05-89, Cambridge Electric Light Company and Commonwealth
Electric Company – 2005 Reconciliation Filing

Dear Secretary Cottrell:

Enclosed for filing are supplemental testimony and exhibits, which provide updates through December 31, 2005 to the initial filing of Cambridge Electric Light Company (“Cambridge”) and Commonwealth Electric Company (“Commonwealth”) d/b/a NSTAR Electric (together, the “Companies”) in this matter.

As part of this supplemental filing, Commonwealth has included the impact of the divestiture of the former power plant property at the Cannon Street Facility in New Bedford. As described in the testimony of Christine L. Vaughan, Commonwealth had, for many years, attempted to lease the property to a non-profit educational entity in accordance with the provisions of Section 341 of the Electric Utility Restructuring Act of 1997 (“Section 341”). Despite such efforts, no agreements were able to be finalized under the provisions of Section 341. Therefore, Commonwealth was required to proceed with the subject divestiture, and it retained the services of an experienced real estate auction firm to proceed with an open, competitive process. As a result of this successful process, Commonwealth customers will receive approximately \$5 million in benefits. Commonwealth requests that the Department of Telecommunications and Energy (the “Department”) find that Commonwealth has maximized the mitigation of transition costs through its divestiture of the Cannon Street Facility.

Included are the following testimony and exhibits:

Exhibit CAM/COM-CLV(Supp)	Supplemental Direct Testimony of Christine L. Vaughan
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Exhibit CAM-CLV-1(Supp)	Transition Charge Calculation (Cambridge)
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Exhibit	Transition	Charge	Calculation
COM-CLV-1(Supp)	(Commonwealth)		
CAM-CLV-2(Supp)	Revenue Credits & Damages, Costs, or Net Recoveries from Claims (Cambridge)		
COM-CLV-2(Supp)	Revenue Credits & Damages, Costs, or Net Recoveries from Claims (Commonwealth)		
CAM-CLV-3(Supp)	Transmission Costs (Cambridge)		
COM-CLV-3(Supp)	Transmission Costs (Commonwealth)		
CAM-CLV-5(Supp)	Basic Service Reconciliation for 2005 (Cambridge)		
COM-CLV-5(Supp)	Basic Service Reconciliation for 2005 (Commonwealth)		
CAM-CLV-6(Supp)	Basic Service Adder Reconciliation for 2005 (Cambridge)		
COM-CLV-6(Supp)	Basic Service Adder Reconciliation for 2005 (Commonwealth)		

Please note that the Companies are not proposing changes to any rates or charges at this time. All of the changes included in this supplemental filing are for reconciling accounts, and will be reflected in rates in subsequent years. An electronic copy of this filing will be submitted separately.

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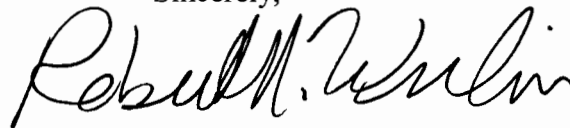
Any correspondence with regard to this filing should be directed to the following:

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Thank you for your attention to this matter.

Sincerely,

A handwritten signature in black ink, appearing to read "Robert N. Werlin". The signature is fluid and cursive, with the first name "Robert" being the most prominent part.

Robert N. Werlin

Enclosures

cc: Shaela McNulty Collins, Hearing Officer
Service List, D.T.E. 04-114

**CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY**

d/b/a NSTAR ELECTRIC

Supplemental Direct Testimony of Christine L. Vaughan

Exhibit CAM/COM-CLV(Supp)

D.T.E. 05-89

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Christine L. Vaughan. My business address is One NSTAR Way,
4 Westwood, Massachusetts, 02090.

5 **Q. Have you previously submitted pre-filed testimony in this proceeding?**

6 A. Yes. As part of the initial filing on December 2, 2005, by Cambridge Electric
7 Light Company (“Cambridge”) and Commonwealth Electric Company
8 (“Commonwealth” or the “Company”; together, the “Companies”), I submitted
9 direct testimony, which has been marked for identification as Exhibit
10 CAM/COM-CLV.

11 **Q. What is the purpose of your supplemental testimony?**

12 A. This testimony is intended to supplement my previous testimony with the purpose
13 of: (1) updating the schedules supporting that testimony with actual data through
14 December 31, 2005; and (2) describing the sale of the Cannon Street Facility. My
15 prior testimony was generally based on actual data through August 2005 only,
16 with estimated data for the remainder of 2005. Exhibit CAM-CLV-1(Supp),
17 Exhibit COM-CLV-1(Supp), Exhibit CAM-CLV-2(Supp), Exhibit COM-CLV-
18 2(Supp), Exhibit CAM-CLV-3(Supp), Exhibit COM-CLV-3(Supp), Exhibit

1 CAM-CLV-5(Supp), Exhibit COM-CLV-5(Supp), Exhibit CAM-CLV-6(Supp)
2 and Exhibit COM-CLV-6(Supp) reflect actual data through the end of 2005.
3 Also, my prior testimony did not include any information regarding the sale of the
4 Cannon Street Facility. This filing has been updated with the results of the sale
5 that occurred on December 28, 2005. With these updates, the Department and the
6 parties to this proceeding can review the final reconciliation of the Transition
7 Charges for the Companies for 2005. The Companies' intention to file this update
8 and the purpose of this update were explained in my prior testimony.

9 **II. RECONCILIATION UPDATE**

10 **Q. Other than updating data for the last portion of the year, are there any other**
11 **changes included in this supplemental filing?**

12 A. Yes. As an initial matter, the Companies have altered the format on page 1 of
13 Exhibit CAM-CLV-1(Supp) and Exhibit COM-CLV-1(Supp), to eliminate the
14 projection of transition charges beyond year 2006. Because this case concerns the
15 reconciliation of 2005 costs and revenues, projections of subsequent years are
16 filed for information purposes, only, and have no bearing on this proceeding.
17 However, the projection for 2006 is included to show the impact of the
18 adjustments of the transition charge implemented in accordance with the terms of
19 the Department-approved Settlement Agreement filed in D.T.E. 05-85. See
20 D.T.E. 05-85, at 3 (2005).

1 **Q. Are there any other changes included in this supplemental filing?**

2 A. Yes, other changes have occurred in various exhibits in this supplemental filing.

3 Set forth below are the exhibits that have been modified with a brief explanation
4 as to the change. A more detailed explanation is provided further below. Exhibit
5 CAM-CLV-1(Supp) and Exhibit COM-CLV-1(Supp) have a new cost item on
6 page 4, column E to recognize residual costs associated with the Seabrook power
7 contract buyout for 2005. Exhibit CAM-CLV-2(Supp) and Exhibit COM-CLV-
8 2(Supp) include new cost items, as well as cost items that were previously
9 estimated to be zero in the initial filing. Exhibit CAM-CLV-3(Supp) and Exhibit
10 COM-CLV-3(Supp) have been modified for formatting and revisions to the
11 revenue requirement calculation of the LNS Transmission and Scheduling and
12 Dispatch costs. Exhibit COM-CLV-5 (Supp), page 2, has been updated to reflect
13 the termination of the Default Service Adjustment on March 1, 2006. Finally, a
14 new Exhibit CAM-CLV-6(Supp) and Exhibit COM-CLV-6(Supp) has been added
15 to calculate the deferral relating to the Basic Service Adder.

16 **Q. Please describe the new cost item associated with the Seabrook Power**
17 **Contract buyout in Exhibit CAM-CLV-1(Supp) and Exhibit COM-CLV-**
18 **1(Supp), page 4, Column E.**

19 A. These amounts reflect the disbursement by Canal Electric Company to
20 Commonwealth and Cambridge of the remaining funds resulting from the sale of
21 Seabrook Station. The amount of disbursement consists of refunds associated

1 with: (1) money held in escrow; (2) NEIL Insurance and (3) American Nuclear
2 Insurers that were netted against invoices for legal and settlement agreement
3 costs. The disbursements were allocated between Commonwealth and Cambridge
4 on the basis of 80.06 percent and 19.94 percent respectively, in accordance with
5 the terms of Canal's contract termination agreement with both parties regarding
6 Seabrook Station.

7 **Q. Please describe the new cost item, the CEC Funding, LLC Securitized Rate**
8 **Reduction Bonds ("RRBs") Transaction Cost Reconciliation in Exhibit**
9 **COM-CLV-2(Supp), page 9.**

10 A. This transaction cost true-up adjustment, as allowed in accordance with
11 G.L. c. 164, § 1H, reconciles the legal and consulting cost of providing, issuing,
12 servicing and retiring the RRBs. These expenses were not finalized at the time of
13 the Issuance Advice Letter dated February 18, 2005, and an estimate of these
14 expenses was included in that Letter. Page 9 of Exhibit COM-CLV-2(Supp)
15 reconciles to actual the estimated transaction costs.

16 **Q. Please describe the Other PPA Buyout Transaction Costs in Exhibit COM-**
17 **CLV-2(Supp), page 10.**

18 A. The Other PPA Buyout Transaction Costs reflect the inclusion of the final legal
19 and consulting costs necessary to complete the buyout/restructuring of purchased
20 power agreements ("PPAs") that were not included in the Securitization
21 Transaction (D.T.E. 04-70). Specifically, the Commonwealth costs relate to the
22 PPA buyout of Altresco-Pittsfield (D.T.E. 04-60) and the restructuring of the PPA

1 with Northeast Energy Associates (D.T.E. 04-85). These costs were allocated
2 among the various electric companies based on the savings each company
3 generated by completing the Purchased Power Agreement Buyouts and
4 Restructurings.

5 **Q. Please describe the two new cost items that were included in Exhibit CAM-**
6 **CLV-2(Supp).**

7 A. The two new cost items are: (1) on page 2 of the exhibit, which sets forth the gain
8 on the Sale of Property located at 199R Concord Turnpike; and (2) on page 4,
9 which reflects the costs that relate to the PPA buyout of Altresco-Pittsfield
10 (D.T.E. 04-60).

11 **Q. How have the Exhibit CAM-CLV-3 and Exhibit COM-CLV-3 been**
12 **reformatted in this supplemental filing?**

13 A. Lines 11 through 16 of Exhibit CAM-CLV-3(Supp), page 1, and Exhibit COM-
14 CLV-3(Supp), page 1, replace lines 11 through 17 of Exhibit CAM-CLV-3, page
15 2 and Exhibit COM-CLV-3, page 2, respectively, which relates to the calculation
16 of the LNS Transmission Revenue Requirement. Exhibit CAM-CLV-3, page 1
17 and Exhibit COM-CLV-3, page 1, as submitted in the initial filing, calculated the
18 forecast average transmission rate per kilowatthour (“kWh”) for the year 2006.
19 Since this page, in each exhibit, does not relate to the reconciliation of 2005 costs
20 and revenues, it has not been included in this supplemental filing.

1 **Q. How has the FERC settlement proceeding in docket ER05-742 affected this**
2 **schedule?**

3 A. The formula rate for the LNS calculation, the results of which are presented on
4 lines 11 through 17 of Exhibit CAM-CLV-3 and Exhibit COM-CLV-3, reflects
5 the Companies' best estimate of the Local Network Service ("LNS") costs that
6 will be recovered as a result of the ongoing FERC proceeding. Elements of the
7 LNS calculation have been combined and simplified from the Companies'
8 original proposal. For example, there is no longer a need for a separate
9 Scheduling and Dispatch (Schedule 1) revenue requirement calculation as it is
10 now part of the monthly transmission revenue requirement. The formula rates
11 established in FERC Docket ER05-742 are effective for both Cambridge and
12 Commonwealth LNS rates as of June 1, 2005. Although settlement negotiations
13 are continuing, the parties are currently dealing with non-rate related terms and
14 conditions that should have no further effect on the actual revenue requirement
15 calculation. However, if there are any further rate changes by the time FERC
16 concludes this docket, the Companies will incorporate any difference into next
17 year's reconciliation filing.

18 **Q. What is the effect of the conceptual changes contained in Exhibit CAM-CLV-**
19 **3(Supp) and Exhibit COM-CLV-3(Supp)?**

20 A. Lines 11 and 12 of Exhibit CAM-CLV-3, page 2, and Exhibit COM-CLV-3, page
21 2, relating to the LNS Transmission Revenue Requirement, were consolidated

1 into line 11 of Exhibit CAM-CLV-3(Supp) and Exhibit COM-CLV-3(Supp),
2 respectively. The Retail Load Ratio percentage of 99.99 percent, shown on line
3 16 of Exhibit COM-CLV-3, page 2, has been changed to 100 percent on line 15 of
4 Exhibit COM-CLV-3(Supp).

5 **Q. Why have these changes occurred?**

6 A. The supplemental exhibit uses a revenue-credit methodology, instead of a load-
7 ratio-share methodology, in calculating wholesale customers' contribution to the
8 revenue requirements for LNS Transmission costs and Dispatch Center costs.
9 The revenue-credit methodology applies the revenues received from the
10 wholesale customers against the total LNS cost of service, the remaining costs to
11 be recovered from retail customers. This revenue-crediting methodology provides
12 that the retail customers pay only for retail use of transmission facilities, while
13 being easier to understand and administer. Thus, the Companies' local network
14 service revenue requirement for retail customers includes a credit for all
15 transmission-related revenues received from any wholesale customer.

16 **Q. What other changes have occurred in the calculation of the revenue**
17 **requirements for LNS Transmission costs and Dispatch Center costs?**

18 A. In accordance with the FERC Order issued on March 24, 2004, in FERC Docket
19 No. ER04-157-000, effective February 1, 2005, the participating New England
20 Transmission Owners, including the Company, filed for a new base Return on
21 Equity ("ROE") for LNS and Regional Network Service ("RNS") of 12.8 percent

1 on its transmission investments as well as certain incentive adders for RTO
2 participation and for new transmission investments. Although the tariff changes
3 have been initially accepted by the FERC for recovery in the transmission rates,
4 they are subject to FERC's final ruling, which is still pending. FERC, however,
5 has indicated in a clarification ruling that the revenues resulting from the ROE
6 adders for RNS rates are not to be included in the revenues credited against the
7 total annual transmission costs for purposes of determining the LNS revenue
8 requirements. Accordingly, in Exhibit CAM-CLV-3(Supp) and Exhibit COM-
9 CLV-3(Supp), the calculation of the LNS revenue requirement and Schedule and
10 Dispatch Center costs, includes a downward adjustment to RNS revenues
11 received from the ISO, to take into effect those revenues associated with the
12 incentive adders. Once the ROE has been finalized, any changes will be flowed
13 through the revenue requirement calculation and will be adjusted, with
14 appropriate carrying charges, in future filings.

15 **Q. Has Exhibit COM-CLV-5 been changed in this supplemental filing other**
16 **than updating the 2005 reconciliation of revenues and expenses?**

17 A. Yes. Page 2 of Commonwealth's forecasted 2006 Basic Service reconciliation
18 has been modified to reduce the Default Service Adjustment to \$0.00000 per kWh
19 effective March 1, 2006, consistent with the Department's approval on February
20 24, 2006 of Commonwealth's filed tariff M.D.T.E. No. 304E.

1 **Q. Please describe the new Exhibit CAM-CLV-6(Supp) and Exhibit COM-**
2 **CLV-6(Supp).**

3 A. Exhibit CAM-CLV-6(Supp) and Exhibit COM-CLV-6(Supp) are two-page
4 exhibits, respectively, that set forth the reconciliation of the revenues and
5 expenses during 2005 and project the costs and revenues for the Basic Service
6 Adder during 2006.

7 **Q. What is the Basic Service Adder?**

8 A. The Basic Service Adder is included in the price for Basic Service to recover
9 administrative costs associated with providing Basic Service that were transferred
10 from distribution rates as required by the Department in D.T.E. 03-88. The costs
11 that are recovered are: (1) Basic Service bad debt costs; (2) administrative cost of
12 compliance with Massachusetts Renewable Energy Portfolio Standard, 225 CMR
13 14.00; (3) the cost of the design and implementation of the competitive bidding
14 process; and (4) the cost of compliance with the Department's Basic Service
15 regulatory requirements, including required communication with the Basic
16 Service customers pursuant to 220 CMR 11.06.

17 **Q. Are the Companies proposing any changes in existing rate levels because of**
18 **the updated information?**

19 A. No. The previously approved rates will remain in effect. The updated data
20 change the calculation of the deferral balances. The revenues and costs for these

1 charges are reconciling, and the updated information will be incorporated into the
2 reconciliation process and be reflected in subsequent rates.

3 **III. DESCRIPTION OF THE CANNON STREET PROPERTY AND THE**
4 **DIVESTITURE PROCESS**

5 **Q. Please describe the sale of property at the Cannon Street Facility.**

6 A. Commonwealth sold the former power plant property at the Cannon Street
7 Facility (the “Facility”) to Sprague Massachusetts Properties LLC (“Sprague”) on
8 December 28, 2005. The site consists of a total of 24.82 acres of property (10.93
9 acres of waterfront land and an additional 13.89 acres of water area subject to all
10 lawful restrictions) located in a waterfront industrial zone in New Bedford,
11 Massachusetts. Included in the sale is a bulk petroleum storage and dispensing
12 facility (“oil terminal”) that has been leased to Global Companies LLC, and the
13 Seller’s former Power Plant Building known as “Cannon Station”. The Facility is
14 located in the Waterfront Industrial Zone per the City of New Bedford zoning
15 regulations and is also entirely within the New Bedford Designated Port Area
16 (“DPA”). Commonwealth received total proceeds of \$12.023 million from
17 Sprague as a result of this transaction.

18 **Q. Why was the Cannon Street Facility sold?**

19 A. The Electric Utility Restructuring Act of 1997 (the “Act”) and Commonwealth’s
20 Restructuring Plan (D.P.U./D.T.E. 97-111) required the Company to divest itself
21 of all generation-related assets and to use any excess proceeds to mitigate

1 stranded costs. The Facility was not included in the initial divestiture auction in
2 1998 (D.T.E. 98-78/83) because it qualified to be excluded, under Section 341 of
3 the Act (“Section 341”), based upon ongoing negotiations with the New Bedford
4 Aquarium Corporation (whose name was later changed to the New Bedford
5 Oceanarium Corporation) (the “Oceanarium”, a non-profit educational entity) to
6 lease the property to it. Section 341 of the Act, which was enacted by the
7 Legislature specifically to apply to Cannon Street, provides that an electric
8 company shall not be required to divest or otherwise include in its transition cost
9 calculation a generation facility that: (1) ceased operation as of January 1, 1993;
10 (2) was retired from rate base; and (3) is subject to a long-term lease with a non-
11 profit, educational entity.

12 **Q. Please describe the background of the lease discussions with the Oceanarium.**

13 A. A lease was signed with the Oceanarium on March 22, 2000. It required the
14 Oceanarium to acquire the financing and permits necessary to build the facility
15 during a two-year due-diligence period. This due-diligence period passed, along
16 with numerous extensions, with the Oceanarium unable to acquire the necessary
17 funding for the project. The lease formally expired on December 15, 2003. Prior
18 to and after the lease expiration, Commonwealth had discussions with the City of
19 New Bedford concerning the acquisition of the site by the New Bedford
20 Redevelopment Authority, but an agreement could not be reached.

1 Commonwealth therefore proceeded with offering the property at a public sale
2 auction.

3 **Q. Please describe the auction process.**

4 A. Commonwealth retained the services of auctioneer JJ Manning to market and to
5 facilitate the sale of the Facility in September 2005. JJ Manning is a renowned
6 real estate auction firm with approximately 30 years experience in the field. Over
7 the years, JJ Manning has marketed and sold more than 13,000 properties through
8 auction processes, totaling purchase prices in excess of \$3 billion. JJ Manning
9 started marketing the property in October 2005 with the setup of a dedicated
10 website, mailing of a marketing brochure to a list of 17,452 individuals and
11 companies, a weekly “blast” e-mail to over 300,000 parties, and advertisements
12 with local, regional and national periodical and industry trade publications. The
13 Facility was sold using a Sealed Bid sale process with all bids due on November
14 30, 2005. Throughout the sale process, JJ Manning conducted an open and
15 competitive process. Confidentiality of all bidders and proposals was maintained
16 and access to information on the property was facilitated through a dedicated
17 website. The website included information regarding the property and offer and
18 provided the following documents: (1) an Offering Memorandum; (2) Title
19 Commitment for the property; (3) Approved Subdivision/ANR Plan and Legal
20 Description for the property; (4) Environmental Conditions and Disclosure

1 Statement; (5) a draft Purchase and Sale Agreement; (6) list of Due Diligence
2 Reports on the property; and (7) Limited Right of Entry Release and Indemnity
3 Agreement. JJ Manning requested that interested parties submit bids on the
4 Facility under an assumption that no significant changes would be made to the
5 Purchase and Sale Agreement, and that the Facility would be sold “as is.”
6 According to JJ Manning’s website statistics, over 1,400 persons downloaded
7 information from the website. A property tour was conducted with 13 prospective
8 bidders on November 16, 2005.

9 Commonwealth received a total of five bid responses on November 30, 2005, of
10 which two were considered conforming. Sprague was, by far, the higher bidder of
11 the two conforming bids. A conforming bid required that the bidder agree to
12 purchase the property based on the purchase and sale agreement included with the
13 Offering Memorandum, without additional conditions. In addition, to be a
14 conforming bid, the bidder had to agree to the following minimum terms: (1) the
15 minimum acceptable bid price for the property was \$500,000; and (2) the Buyer
16 had to provide a bond, cash deposit, or irrevocable letter of credit, each in a form
17 and amount equal to \$3,250,000 to Commonwealth, to fully secure the Buyer’s
18 obligations with respect to the environmental abatement work at Cannon Station
19 per a Scope of Work provided by Commonwealth. In addition, the Buyer had to
20 agree to complete all abatement of all asbestos and regulated materials located

1 within Cannon Station per the Scope of Work within five years from the Closing
2 Date of the property.

3 **Q. Please describe the agreements between Commonwealth and Sprague**
4 **relating to the sale of the Cannon Street Facility.**

5 A. The two parties signed the Purchase and Sale Agreement (“PSA”) on
6 December 16, 2005. It provided for the transfer of the property described above
7 to Sprague for the sum of \$12.023 million. The property was sold “as is” with all
8 faults, including the assignment and transfer of all environmental liability to the
9 Buyer, including one specific Massachusetts Department of Environmental
10 Protection listed site on the property. Commonwealth committed to remediate a
11 portion of the site to achieve a Class A-4 Partial Remedial Action Outcome
12 (“RAO”) with an Activity Use Limitation (“AUL”). The deed includes a release
13 by Sprague, a covenant not to sue and indemnity protections for the benefit of
14 Commonwealth, its successors and assigns, which will run with the title to the
15 property. In addition, Sprague provided Commonwealth a letter of credit equal to
16 \$3.25 million to fully secure Sprague’s obligation with respect to the
17 environmental abatement work at the Cannon Station located on the property per
18 the Scope of Work provided in the Offering Memorandum. Additionally, an
19 Access and Cooperation Agreement was signed by both parties. This agreement
20 allows for the relocation of certain distribution electrical facilities and warehouse
21 stock, for access to complete certain environmental work and to establish

1 easements on each others property to access their own property. Title on the
2 Facility was transferred on December 28, 2005. The sale results were excellent in
3 that Commonwealth and its customers secured significant proceeds for the
4 property and avoided exposure for substantial environmental liabilities in the
5 future.

6 **Q. Was the Cannon Street Facility operating as a generation facility at the time**
7 **of the Sale?**

8 A. No. The Facility has been retired as a generation facility effective December 18,
9 1992. In that time period, two separate accounting transactions occurred. First,
10 the land at the Cannon Station and the land and net plant relating to the oil
11 terminal facility (leased to Global Petroleum) was transferred from production
12 plant (FERC Accounts 101 and 108) to non-utility plant (FERC Accounts 121 and
13 122). The property had a net book value of \$0.7 million at the time of transfer.
14 Second, buildings and equipment specific to the Cannon Street power plant were
15 transferred from production plant to a regulatory asset account (FERC Account
16 182), which was subsequently recovered from customers in the transition charge.
17 See Cambridge Electric Light Company/Commonwealth Electric Company,
18 D.T.E. 99-90-C (2001) and Figure 1 below. The oil terminal facility and land had
19 been maintained as a non-utility investment from 1993 to the present. During that
20 time, various items, such as investment in a new seawall, designation of the
21 property as located in the Waterfront Industrial Zone for the City of New Bedford

1 and within the New Bedford Designated Port Area, and leasehold improvements
2 to the oil terminal facility have all increased the value of the Facility.
3 Commonwealth is not seeking recovery from customers relating to any of these
4 new investments and improvements.

5 **Figure 1: Cannon Street Elements**

\$ millions	Est Mkt Value 1993	Net Plant Value 1993	
Equipment	NA	\$0	} Abandoned Property Recovered in Transition charge
Building	\$0.53	\$0	
Land	\$1.09	\$0.67	} Non-Utility Transferred to Non-Utility
Oil Terminal	\$1.06		
Total	\$2.68	\$0.67	

6 **Q. Has an appraisal been prepared for the Cannon Street Facility?**

7 A. Yes. To help determine the market value for the Facility, Commonwealth
8 commissioned an appraisal analysis from Meredith & Grew, which is included as
9 Exhibit COM-CLV-7. The report established an estimated market value of the
10 Facility on January 1, 1993 (date of transfer to non-utility property) of \$2.68
11 million and is summarized in Figure 2 below. Using the same methodology, it
12 also established an estimated market value of the Facility on December 28, 2005
13 (date of sale to Sprague) of \$5.69 million. Three components were separately
14 valued in order to determine the total valuation. First, the oil terminal was valued

1 with the income approach. This methodology projected the rental value from the
2 oil terminal and discounts this income stream to obtain a valuation. The valuation
3 of the oil terminal was \$3.17 million for 2005 and \$1.06 million for 1993. The
4 second component of the valuation was the power plant building and this was
5 valued with the sales comparison approach. The value of comparable properties
6 was split into land and building components. Based on the dollar-per-square-foot
7 of the building component of comparable properties for the time of valuation, and
8 an understanding of the environmental mitigation efforts at the time, Meredith &
9 Grew determined a value for the power plant building. In both time periods, the
10 power plant was valued at \$0.53 million. The third and final component of the
11 valuation was for the land. This also used the sales comparison approach. Based
12 on the land comparables, the value of the land was determined to be \$1.09 million
13 for 1993 and \$1.99 million for 2005.

14
Figure 2: Valuation Results

\$ millions	Est Mkt Value 1993	Est Mkt Value 2005
Building	\$0.53	\$0.53
Land	\$1.09	\$1.99
Oil Terminal	\$1.06	\$3.17
Total	\$2.68	\$5.69

1 **Q. Why do you believe that Commonwealth's divestiture process has maximized**
2 **the value of the Facility?**

3 A. Commonwealth used an open and competitive process to market the Facility,
4 resulting in a bid for the property that far exceeded the appraised value of the
5 Facility. The Facility was actively marketed to likely potential bidders locally,
6 regionally and nationally, as well as to the City of New Bedford. In particular, JJ
7 Manning's expertise in selling industrial properties was an important element in
8 the transaction.

9 Commonwealth's success in obtaining such a high value for the Facility occurred
10 despite of the fact that the Facility has been retired for approximately 13 years and
11 the Facility's structure is not in pristine condition. Moreover, Commonwealth's
12 efforts to negotiate a transaction with the City of New Bedford at various times
13 over the past several years resulted in Commonwealth placing the Facility on the
14 market after the height of the recent boon in the real estate market. Accordingly,
15 in light of the condition of the Facility and a stagnated real estate market
16 generally, Commonwealth believes that it has achieved the maximum value of the
17 Facility through an open and competitive marketing effort.

**IV. EFFECT OF THE SALE OF THE FACILITY ON THE
COMMONWEALTH'S TRANSITION CHARGE**

Q. How does Commonwealth propose to reflect the Sale of the Cannon Street Facility in the Transition Charge?

A. Commonwealth proposes to reflect the Sale of the Facility as a variable component of the Transition Charge. The detail supporting the excess proceeds to be given to customers is found on page 4 of Exhibit COM-CLV-2(Supp). The first 23 lines calculate the net proceeds from the sale. The detail starts by taking the Total Sale Proceeds of \$12.023 million and reducing it by \$1.139 million for Closing Costs to compute the Net Sale Proceeds of \$10.885 million. The Net Sale Proceeds are then reduced for Make-Ready and Other Transaction Costs of \$0.490 million to determine the Net Sale Proceeds after Transaction Costs of \$10.394 million. At this point, Commonwealth proposes to set aside \$2.3 million to complete Post-Closing Construction Costs, which reduces the Net Proceeds to \$8.094 million. Post-Closing Construction Costs relate to provisions within the sale agreement that require Commonwealth to complete two construction projects by the end of 2007. The Environmental Remediation project is estimated at \$1.5 million and will complete the environmental work described in Section 6.2 of the Purchase and Sale Agreement. The Equipment Relocation project is estimated at \$0.8 million and is needed to move existing distribution equipment off the land that was sold to Sprague. The scope of the work necessary to relocate the distribution equipment is identified in Exhibit B of the Access and Cooperation

1 Agreement between Commonwealth and Sprague. Since these amounts are
2 estimates, Commonwealth proposes to reconcile the amounts to actual once the
3 projects are completed.

4 **Q. How does Commonwealth propose to determine the proceeds to flow back to**
5 **customers?**

6 A. Commonwealth proposes a three-step process to calculate the allocation of Net
7 Proceeds between the customers and Commonwealth. The first step is to
8 determine the gain that would have been given back to customers at the time of
9 the retirement of the Facility from rate base and its transfer to non-utility property
10 on December 18, 1992. Department precedent indicates that transfers to affiliates
11 be at the higher of net book or market value. Boston Edison Company,
12 D.P.U./D.T.E. 97-63, at 33 (1998). The Appraisal Report referenced above
13 establishes the Fair Market Value of the Facility at the end of 1992 as \$2.680
14 million. The Net Plant Value at the same time was \$0.671 million. Hence, the
15 transfer price at the time of retirement should be \$2.680 million. The difference is
16 the net gain to be given back to customers of \$2.009 million. Lines 26 to 34 of
17 Page 4 of Exhibit COM-CLV-2(Supp) show this calculation.

18 The second step is to determine the appreciation in value of the Facility between
19 the end of 1992 and the end of December 2005, when Commonwealth held the
20 property as a non-utility asset. The Appraisal Report referenced above (Exhibit
21 COM-CLV-7) establishes the Fair Market Value of the Facility at the end of

1 December 2005 as \$5.692 million, when calculated in the same manner as the
2 1992 value. The increase in the Fair Market Values between December 1992 and
3 December 2005 results in a gain to be retained by Commonwealth of \$3.012
4 million. Lines 36 to 41 of Page 4 of Exhibit COM-CLV-2(Supp) show this
5 calculation.

6 The third step reflects the fact that the auction was very successful and
7 Commonwealth received an amount significantly higher than the appraised
8 market values, even after adjusting for transaction, closing and post-closing costs.
9 The calculation takes the Net Proceeds and reduces it by the gains calculated in
10 the previous two steps. Because there is no way to determine with certainty
11 whether the “extraordinary” gain of \$3.074 million would have been available in
12 1992 (when the Facility was transferred to non-utility property), it is not possible
13 to apportion definitively this gain between customers and Commonwealth.
14 Accordingly, Commonwealth proposes to credit customers with the entirety of
15 this extraordinary gain.

16 The Total Customer Gain of \$5.083 million, shown on line 53 of page 4 of
17 Exhibit COM-CLV-2(Supp), is the sum of lines 34 and 51 and flows to page 1,
18 column C of that Exhibit and ultimately is shown on pages 1 and 4 of Exhibit
19 COM-CLV-1(Supp). Any changes to the Net Proceeds resulting from the true-up
20 of the Post-Closing Construction Costs will be adjusted in future filings.

1 **Q.** **Does this conclude your testimony?**

2 **A.** Yes.

**Cambridge Electric Light Company
Transition Charge Calculation
\$ in Millions**

Year	GWH Delivered	Transition Charge	Revenues for Delivered GWH	Total			Prior Year Deferral	Interest on Deferral	Expenses	(Over) Under Collection
				Fixed Component	Variable Component	Mitigation Incentive & Other				
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2004										\$ (0.964)
2005	1,715.387	0.377	6.473	(1.648)	21.309	0.303	(0.964)	(0.016)	18.983	12.510
Jan-Apr	565.668	1.632	9.233	(0.487)	5.021	0.097	4.018	0.096	8.744	(0.490)
May-Dec	1,195.520	1.489	17.805	(1.030)	10.611	0.204	8.492	0.202	18.480	0.675
2006	1,761.188	1.535	27.038	(1.517)	15.632	0.301	12.510	0.298	27.224	0.185

Col. B: 2005 per Page 2, Line 15; year 2006 per sales forecast.

Col. C: 2005 per Page 2, Line 15; year 2006 per D.T.E. 05-85 Settlement Agreement - Jan to Apr, Article 2.2; May to Dec Article 2.4

Col. D: 2005 per Page 2, Line 15; year 2006 = Col. B* Col. E/ 100.

Col. E: Page 3, Col. F.

Col. F: Page 4, Col. I.

Col. G: Page 5, Col. J.

Col. H: Col. K prior year.

Col. I: Col. J times interest rate on customer deposits; 2004 ending balance = 1.65%; 2005 ending balance = 2.38%; Post 2005 = 10.88%.

Col. J: Sum of Col. E thru Col. I.

Col. K: 2004 per D.T.E. 03-118/04-114 (Settlement); 2005 and beyond equals Col. J - Col. D.

Cambridge Electric Light Company
Actual 2005 Transition Revenues
\$ in Millions

Line	Description	GWH	A/C #	Per Book \$	Total
1	<u>Actual 2005 Transition Billed Revenues:</u>				
2	Residential Transition	194.524	440160	\$ 0.720	
3	Commercial Transition	1,482.406	442500	5.512	
4	Industrial Transition	31.260	442430	0.122	
5	Street Light Transition	8.226	444060	0.032	
6	Total Billed Revenues	<u>1,716.417</u>			\$ 6.385
7	<u>Actual 2005 Transition Unbilled Revenues:</u>			<u>Value</u>	
8	Less: Residential Transition Unbilled @ 12/31/04	(9.618)			
9	Plus: Residential Transition Unbilled @ 12/31/05	9.572	440162	\$ 0.015	
10	Less: Commercial Transition Unbilled @ 12/31/04	(64.300)			
11	Plus: Commercial Transition Unbilled @ 12/31/05	63.416	442505	0.073	
12	Less: Industrial Transition Unbilled @ 12/31/04	(1.344)			
13	Plus: Industrial Transition Unbilled @ 12/31/05	1.245	442435	0.001	
14	Total Unbilled Revenues	<u>(1.029)</u>			0.088
15	Total Actual 2005 Transition Revenues	<u>1,715.387</u>	<u>0.377</u>		\$ 6.473

Cambridge Electric Light Company
Summary of Transition Charge - Fixed Component
\$ in Millions

Year	Cambridge Electric Light Company		Residual Value Credit		Net Fixed Component
	Pre-Tax Return on Generation Related Assets	Amortization of Generation Related Assets	Pre-Tax Return on Cambridge Generation Recovery/(Proceeds)	Amortization of Cambridge Generation Recovery/(Proceeds)	
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F
2005	\$ 0.009	\$ 0.024	\$ (0.600)	\$ (1.081)	\$ (1.648)
2006	0.007	0.024	(0.467)	(1.081)	(1.517)
2007	0.006	0.024	(0.334)	(1.081)	(1.385)
2008	0.004	0.024	(0.200)	(1.081)	(1.253)
2009	0.001	0.029	(0.067)	(1.083)	(1.120)

Note: Amounts per D.T.E. 03-118/04-114(Settlement), Exhibit CAM-CLV-2A.
Col. F equals Sum of Col. B through Col. E.

Cambridge Electric Light Company
Summary of Transition Charge - Variable Component
\$ in Millions

Year	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Power Contract Buyouts	Revenue Credits & Damages, Costs, or net Recoveries	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2005	28.421	5.790	22.631	(0.038)	(2.224)	0.567	0.372	21.309
2006	20.751	4.015	16.736	-	-	(0.537)	(0.567)	15.632
2007	21.604	3.527	18.077	-	-	-	0.537	18.614
2008	20.665	3.650	17.015	-	-	-	-	17.015
2009	10.320	4.067	6.253	-	-	-	-	6.253
2010	9.993	3.950	6.043	-	-	-	-	6.043
2011	4.734	4.155	0.579	-	-	-	-	0.579
2012	1.511	1.049	0.462	-	-	-	-	0.462
2013	0.462	-	0.462	-	-	-	-	0.462
2014	0.461	-	0.461	-	-	-	-	0.461
2015	0.463	-	0.463	-	-	-	-	0.463
2016	0.329	-	0.329	-	-	-	-	0.329
2017	0.365	-	0.365	-	-	-	-	0.365
2018	0.378	-	0.378	-	-	-	-	0.378
2019	0.391	-	0.391	-	-	-	-	0.391
2020	0.406	-	0.406	-	-	-	-	0.406
2021	0.569	-	0.569	-	-	-	-	0.569

Col. B: Page 6, Col. M.

Col. C: Page 7, Col. M.

Col. D: Col. B - Col. C (see also Page 8, Col. M).

Col. E: Celco's share of Seabrook Power Contract Buyout Adjustment

Col. F: Exhibit CAM-CLV-2 (Supp), Page 1, Col. L.

Col. G: Exhibit CAM-HCL-7, Page 1, Col. E adjusted for rate design constraint

Col. H: Reversal of Prior Year Col. G.

Col. I: Col. D + Col. E + Col. F + Col. G + Col. H.

Cambridge Electric Light Company
Summary of Transition Charge - Other Adjustments
\$ in Millions

Year	EIS Return on Investment Adjustment	Mitigation Incentive Adjustment	Other Adjustment	Mitigation Incentive					Total Other Adjustments
				Hydro Quebec Transmission	Fixed Component	Seabrook Buydown	Vermont Yankee Buydown	Seabrook Buyout	
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
2005		0.006	(0.050)	0.005	0.117	0.120	0.060	0.045	0.303
2006		-		0.006	0.111	0.117	0.022	0.045	0.301
2007		-		0.006	0.105	0.114	0.063	0.025	0.313
2008		-		0.006	0.099	0.110	0.066	0.040	0.321
2009		-		0.006	0.093	0.106	0.029	0.043	0.277
2010		-		0.006		0.103	0.070	0.021	0.200
2011		-		0.006		0.100	0.059	0.039	0.204
2012		-		0.006		0.096	0.072	0.041	0.215
2013		-		0.006		0.093		0.020	0.119
2014		-		0.006		0.089		0.042	0.137
2015		-		0.006		0.086		0.042	0.134
2016		-		0.006		0.083		0.008	0.097
2017		-		0.006		0.079		0.032	0.117
2018		-		0.006		0.075		0.033	0.114
2019		-		0.006		0.073		0.008	0.087
2020		-		0.006		0.069		0.035	0.110
2021		-		0.006		0.065		0.038	0.109
2022		-				0.063		0.012	0.075
2023		-				0.059		0.042	0.101
2024		-				0.055		0.046	0.101
2025		-				0.051		0.015	0.066
2026		-				0.046		0.040	0.086

Col. C: Annual True-up for Col. H., plus 4 % of Seabrook Buyout Adjustment (page 4, column E)

Col. D: 2005 adjustment per DTE 04-60 Altresco-Pittsfield Order Page 26 footnote 9.

Col. E: Equals 4 percent of Page 6, Col. F.

**Cambridge Electric Light Company
Power Contract Obligations
Annual Obligations in Millions of Dollars**

Year	Vermont Yankee	Altresco- Pittsfield	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Line 331 Equalizer	Canal Section A	Canal Section B	Yankee Atomic	Connecticut Yankee	Maine Yankee	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
Jan - Feb	\$ 0.716	\$ 2.505	\$ 0.024	\$ 0.108	\$ (0.018)	\$ 0.024	\$ -	\$ 0.024	\$ 0.182	\$ 0.674	\$ 0.357	\$ 4.597
Mar - Dec	3.307	12.525	0.093	0.415	(0.096)	0.037	-	0.036	0.906	4.599	2.003	23.824
2005	\$ 4.022	\$ 15.030	\$ 0.116	\$ 0.523	\$ (0.114)	\$ 0.061	\$ -	\$ 0.060	\$ 1.089	\$ 5.274	\$ 2.360	\$ 28.421
2006	4.008	5.010	0.062	0.609	(0.150)	-	-	-	1.314	7.504	2.394	20.751
2007	3.527	10.020	0.035	0.603	(0.150)	-	-	-	0.261	4.993	2.315	21.604
2008	3.650	10.020	0.036	0.596	(0.150)	-	-	-	0.258	4.185	2.070	20.665
2009	4.067	-	0.037	0.591	(0.150)	-	-	-	0.258	4.185	1.333	10.320
2010	3.950	-	0.038	0.586	(0.150)	-	-	-	0.258	4.185	1.126	9.993
2011	4.264	-	0.039	0.581	(0.150)	-	-	-	-	-	-	4.734
2012	1.045	-	0.040	0.576	(0.150)	-	-	-	-	-	-	1.511
2013	-	-	0.041	0.571	(0.150)	-	-	-	-	-	-	0.462
2014	-	-	0.043	0.568	(0.150)	-	-	-	-	-	-	0.461
2015	-	-	0.044	0.569	(0.150)	-	-	-	-	-	-	0.463
2016	-	-	0.045	0.434	(0.150)	-	-	-	-	-	-	0.329
2017	-	-	0.047	0.468	(0.150)	-	-	-	-	-	-	0.365
2018	-	-	0.048	0.480	(0.150)	-	-	-	-	-	-	0.378
2019	-	-	0.049	0.492	(0.150)	-	-	-	-	-	-	0.391
2020	-	-	0.051	0.505	(0.150)	-	-	-	-	-	-	0.406
2021	-	-	0.053	0.666	(0.150)	-	-	-	-	-	-	0.569

Note: 2005 (Jan - Feb) per Exhibit CAM-CLV-4, Page 3.
2005 (Mar - Dec) - 10 months actual.
Post 2005 per Company forecasts.

**Cambridge Electric Light Company
Power Contract Obligations
Annual Market in Millions of Dollars**

Year	Vermont Yankee	Altresco- Pittsfield	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Line 331 Equalizer	Canal Section A	Canal Section B	Yankee Atomic	Connecticut Yankee	Maine Yankee	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
Jan - Feb	\$ (1.165)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1.165)
Mar - Dec	6.954	-	-	-	-	-	-	-	-	-	-	6.954
2005	\$ 5.790	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5.790
2006	4.015	-	-	-	-	-	-	-	-	-	-	4.015
2007	3.527	-	-	-	-	-	-	-	-	-	-	3.527
2008	3.650	-	-	-	-	-	-	-	-	-	-	3.650
2009	4.067	-	-	-	-	-	-	-	-	-	-	4.067
2010	3.950	-	-	-	-	-	-	-	-	-	-	3.950
2011	4.155	-	-	-	-	-	-	-	-	-	-	4.155
2012	1.049	-	-	-	-	-	-	-	-	-	-	1.049
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-

Note: 2005 (Jan - Feb) per Exhibit CAM-CLV-6, Page 2.
2005 (Mar - Dec) - 10 months actual.
Post 2005 per Company forecasts.

**Cambridge Electric Light Company
Power Contract Obligations
Annual Above Market in Millions of Dollars**

Year	Vermont Yankee	Altresco- Pittsfield	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Line 331 Equalizer	Canal Section A	Canal Section B	Yankee Atomic	Connecticut Yankee	Maine Yankee	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
Jan - Feb	\$ 1.881	\$ 2.505	\$ 0.024	\$ 0.108	\$ (0.018)	\$ 0.024	\$ -	\$ 0.024	\$ 0.182	\$ 0.674	\$ 0.357	\$ 5.762
Mar - Dec	(3.648)	12.525	0.093	0.415	(0.096)	0.037	-	0.036	0.906	4.599	2.003	16.870
2005	\$ (1.767)	\$ 15.030	\$ 0.116	\$ 0.523	\$ (0.114)	\$ 0.061	\$ -	\$ 0.060	\$ 1.089	\$ 5.274	\$ 2.360	\$ 22.631
2006	(0.007)	5.010	0.062	0.609	(0.150)	-	-	-	1.314	7.504	2.394	16.736
2007	-	10.020	0.035	0.603	(0.150)	-	-	-	0.261	4.993	2.315	18.077
2008	-	10.020	0.036	0.596	(0.150)	-	-	-	0.258	4.185	2.070	17.015
2009	-	-	0.037	0.591	(0.150)	-	-	-	0.258	4.185	1.333	6.253
2010	-	-	0.038	0.586	(0.150)	-	-	-	0.258	4.185	1.126	6.043
2011	0.109	-	0.039	0.581	(0.150)	-	-	-	-	-	-	0.579
2012	(0.004)	-	0.040	0.576	(0.150)	-	-	-	-	-	-	0.462
2013	-	-	0.041	0.571	(0.150)	-	-	-	-	-	-	0.462
2014	-	-	0.043	0.568	(0.150)	-	-	-	-	-	-	0.461
2015	-	-	0.044	0.569	(0.150)	-	-	-	-	-	-	0.463
2016	-	-	0.045	0.434	(0.150)	-	-	-	-	-	-	0.329
2017	-	-	0.047	0.468	(0.150)	-	-	-	-	-	-	0.365
2018	-	-	0.048	0.480	(0.150)	-	-	-	-	-	-	0.378
2019	-	-	0.049	0.492	(0.150)	-	-	-	-	-	-	0.391
2020	-	-	0.051	0.505	(0.150)	-	-	-	-	-	-	0.406
2021	-	-	0.053	0.666	(0.150)	-	-	-	-	-	-	0.569

Note: Annual Above Market = Annual Obligation (page 6) minus Annual Market (page 7).

Cambridge Electric Light Company
Revenue Credits & Damages, Costs, or Net Recoveries from Claims
\$ in Millions

<u>Year</u>	<u>Future Use</u>	<u>Claims and Recoveries</u>	<u>Sales of Property</u>	<u>Future Use</u>	<u>Future Use</u>	<u>Future Use</u>	<u>Future Use</u>	<u>Future Use</u>	<u>Standard Offer Revenues</u>	<u>Future Use</u>	<u>Other PPA Transaction Costs</u>	<u>Total</u>
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2005	\$ -	\$ -	\$ (0.148)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (2.102)	\$ -	\$ 0.027	\$ (2.224)
2006	-	-	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-

Notes: Col. C per Page 2.
Col. I per Page 3.
Col. K per Page 4.
Col. L equals Sum of Col. A thru Col. K.

Cambridge Electric Light Company					
Property Sales					
\$ in Millions					
<u>Description</u>	<u>Sale Date</u>	<u>Book Value</u>	<u>Sale Proceeds</u>	<u>Transaction Costs</u>	<u>Gain/ (Loss)</u>
Sale of 199R Concord Turnpike	January 7, 2005	\$0.001	\$0.150	\$0.001	\$ 0.148
Total Estimated Gain on Properties Sold - 2004					<u>\$ 0.148</u>

Cambridge Electric Light Company
Post Standard Offer Period Revenues
\$ in Millions

<u>Line</u>	<u>Description</u>	<u>Account</u>	<u>Actual</u> <u>Mar-05</u>	<u>Actual</u> <u>Apr-05</u>	<u>Actual</u> <u>May-05</u>	<u>Actual</u> <u>Jun-05</u>	<u>Actual</u> <u>Jul-05</u>	<u>Actual</u> <u>Aug-05</u>	<u>Actual</u> <u>Sep-05</u>	<u>Actual</u> <u>Oct-05</u>	<u>Nov-05</u>	<u>Dec-05</u>	<u>Total</u>
1	Standard Offer Revenues												
2	Residential	440170	\$0.049	\$(0.001)	\$(0.001)	\$ 0.000	\$(0.000)	\$(0.000)	\$(0.000)	\$(0.000)	\$ -	\$ -	\$ 0.048
3	Commercial	442450	1.954	0.059	0.006	(0.001)	(0.003)	(0.000)	-	0.000	0.000	0.000	2.014
4	Industrial	442460	0.037	-	-	-	-	-	-	-	-	-	0.037
5	Street Lighting	444070	0.003	(0.000)	0.000	-	-	-	-	-	-	-	0.003
6	Total Standard Offer Revenues		<u>\$2.043</u>	<u>\$ 0.058</u>	<u>\$ 0.005</u>	<u>\$(0.001)</u>	<u>\$(0.003)</u>	<u>\$(0.000)</u>	<u>\$(0.000)</u>	<u>\$(0.000)</u>	<u>\$0.000</u>	<u>\$0.000</u>	<u>\$ 2.102</u>

Cambridge Electric Light Company
Other PPA Buyout Transaction Costs
\$ in Millions

<u>Line #</u>	<u>Vendor</u>	<u>Amount</u>	<u>Allocated to</u> <u>Securitization</u>	<u>Other PPA</u> <u>Amount</u>		
1	Concentric Energy Advisors	\$ 0.671	\$ 0.400	\$ 0.270		
2	Keegan Werlin	\$ 0.637	\$ 0.377	\$ 0.260		
3	Ropes & Gray	\$ 0.065	\$ 0.039	\$ 0.026		
4	Total Other Transaction Costs	<u>\$ 1.373</u>	<u>\$ 0.816</u>	<u>\$ 0.556</u>		
5						
6		<u>BECo.</u>	<u>COM</u>	<u>CAM</u>	<u>Total</u>	
7	Other PPA Transaction Costs	\$ 0.056	\$ 0.474	\$ 0.027	\$ 0.556	

Cambridge Electric Light Company
2005 Retail Transmission Cost
\$ in Millions

Line	Description	Tariff	Account	Dec-04	Actual Jan-05	Actual Feb-05	Actual Mar-05	Actual Apr-05	Actual May-05	Actual Jun-05	Actual Jul-05	Actual Aug-05	Actual Sep-05	Actual Oct-05	Actual Nov-05	Actual Dec-05	Total
Regional Transmission Costs																	
1	Retail RNS Cost	ISO Schedule 9	565590		\$ 0.527	\$ 0.418	\$ 0.417	\$ 0.432	\$ 0.518	\$ 0.663	\$ 0.676	\$ 0.640	\$ 0.744	\$ 0.643	\$ 0.625	\$ 0.600	\$ 6.904
2	Regional Ancillary Services																
3	Retail Schedule & Dispatch Cost	ISO Schedule 1	561140		0.033	0.036	0.037	0.034	0.039	0.037	0.038	0.047	0.054	0.054	0.051	0.043	0.503
4	Retail Congestion Management Cost	Note A	565210		0.801	0.963	1.663	1.426	1.140	1.110	1.351	2.168	2.406	1.666	0.522	0.078	15.294
5	System Restoration & Planning Cost	ISO Schedule 16	565060		0.009	0.007	0.008	0.008	0.009	0.011	0.022	0.008	0.009	0.009	0.009	0.011	0.119
6	Load Dispatching (REMVEC II)	ISO Schedule 1	561110		-	-	-	-	-	-	-	-	-	-	-	-	-
7	VAR Support Cost	ISO Schedule 2			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total Regional Transmission Costs				1.370	1.424	2.125	1.900	1.705	1.821	2.087	2.863	3.212	2.371	1.207	0.732	22.819
Local Transmission Costs																	
9	Determination of Local Network Service (LNS) Costs																
11	Monthly Transmission Revenue Requirement	ISO Schedule 21 *			\$ 1.243	\$ 1.355	\$ 1.355	\$ 1.355	\$ 1.355	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 17.498
12	Monthly Dispatch Center Revenue Requirement	Note B	566710		0.002	0.002	0.003	0.002	0.002	-	-	-	-	-	-	-	0.010
13	Schedule 1 Revenues Received	ISO Schedule 1	456920		-	-	-	-	-	-	-	-	-	-	-	-	-
14	LNS Revenue Requirement				\$ 1.245	\$ 1.356	\$ 1.357	\$ 1.356	\$ 1.356	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 17.508
15	Retail Load Ratio				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Retail LNS Revenue Requirement				\$ 1.245	\$ 1.356	\$ 1.357	\$ 1.356	\$ 1.356	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 1.548	\$ 17.508
17																	
18	Total Transmission Costs				\$ 2.615	\$ 2.780	\$ 3.482	\$ 3.256	\$ 3.062	\$ 3.369	\$ 3.635	\$ 4.412	\$ 4.760	\$ 3.919	\$ 2.755	\$ 2.281	\$ 40.327
Transmission Revenues Detail																	
19	Residential		440140		\$ 0.459	\$ 0.438	\$ 0.415	\$ 0.337	\$ 0.305	\$ 0.442	\$ 0.438	\$ 0.506	\$ 0.454	\$ 0.365	\$ 0.394	\$ 0.444	\$ 4.995
21	Commercial		442380		1.623	1.880	1.777	2.083	1.870	2.867	2.737	2.473	2.515	2.227	2.171	1.608	25.830
22	Industrial		442400		0.028	0.029	0.028	0.039	0.035	0.031	0.046	0.050	0.047	0.039	0.031	0.028	0.430
23	Street Lighting		444050		0.015	0.015	0.015	0.022	0.006	0.014	0.014	0.014	0.014	0.014	0.015	0.014	0.172
24	Transmission Revenues				\$ 2.124	\$ 2.361	\$ 2.234	\$ 2.481	\$ 2.216	\$ 3.353	\$ 3.234	\$ 3.043	\$ 3.031	\$ 2.645	\$ 2.611	\$ 2.094	\$ 31.427
25	Retail Transmission Deferral (Over)/Under Collection				\$ 0.491	\$ 0.419	\$ 1.248	\$ 0.775	\$ 0.846	\$ 0.016	\$ 0.401	\$ 1.369	\$ 1.730	\$ 1.274	\$ 0.145	\$ 0.186	\$ 8.899
26	Interest on Transmission Deferral Balance				0.020	0.021	0.023	0.025	0.027	0.028	0.028	0.030	0.033	0.036	0.038	0.038	0.347
27	Transmission Deferral (Over)/Under Ending Balance		182874	\$ 10.041	\$ 10.552	\$ 10.992	\$ 12.263	\$ 13.064	\$ 13.936	\$ 13.980	\$ 14.410	\$ 15.808	\$ 17.571	\$ 18.881	\$ 19.063	\$ 19.287	
28	Annual Interest Rate				2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	

Note A: ISO Schedule 19 (SCR) and Market Rule 1 (RMR)

Note B: Schedule 1 of ISO Schedule 21

* Amount includes revenue credit of wholesale customer revenues

[illegible]

[illegible]

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**Commonwealth Electric Company
Transition Charge Calculation
\$ in Millions**

Year	GWH Delivered	Transition Charge	Revenues for Delivered GWH	Total			Prior Year Deferral	Interest on Deferral	Expenses	(Over) Under Collection
				Fixed Component	Variable Component	Mitigation Incentive & Other				
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2004										\$ 132.016
2005	4,367.434	2.677	116.916	0.062	74.486	(129.853)	132.016	2.178	78.890	(38.025)
Jan-Apr	1,478.335	2.441	36.090	-	43.311	0.004	(12.569)	(0.299)	30.447	(5.644)
May-Dec	2,994.125	2.298	68.814	-	87.719	0.008	(25.456)	(0.606)	61.665	(7.149)
2006	4,472.460	2.346	104.904	-	131.030	0.012	(38.025)	(0.905)	92.111	(12.793)

Col. B: 2005 per Page 2, Line 15; year 2006 per sales forecast.

Col. C: 2005 per Page 2, Line 15; year 2006 per D.T.E 05-85 Settlement Agreement - Jan to Apr, Article 2.2; May to Dec Article 2.4

Col. D: 2005 per Page 2, Line 15; year 2006 = Col. B* Col. E/ 100.

Col. E: Page 3, Col. F.

Col. F: Page 4, Col. I.

Col. G: Page 5, Col. L.

Col. H: Col. M prior year.

Col. I: Col. H times interest rate on customer deposits; 2004 ending balance = 1.65%; 2005 ending balance = 2.38%; Post 2005 = 10.88%.

Col. J: Sum of Col. E thru Col. I.

Col. K: 2004 per D.T.E. 03-118/04-114 (Settlement); 2005 and beyond equals Col. J - Col. D.

Commonwealth Electric Company

Actual 2005 Transition Revenues

\$ in Millions

Line	Description	GWH	A/C #	Per Book \$	Total
1	<u>Actual 2005 Transition Billed Revenues:</u>				
2	Residential Transition	2,139.560	440160	\$ 56.449	
3	Commercial Transition	1,845.504	442500	48.547	
4	Industrial Transition	363.132	442430	9.642	
5	Street Light Transition	15.767	444060	0.420	
6	Total Billed Revenues	4,363.964			\$ 115.058
7	<u>Actual 2005 Transition Unbilled Revenues:</u>				
8	Less: Residential Transition Unbilled @ 12/31/04	(112.040)			
9	Plus: Residential Transition Unbilled @ 12/31/05	112.743	440162	\$ 0.951	
10	Less: Industrial Transition Unbilled @ 12/31/04	(13.683)			
11	Plus: Industrial Transition Unbilled @ 12/31/05	13.744	442435	0.165	
12	Less: Commercial Transition Unbilled @ 12/31/04	(81.369)			
13	Plus: Commercial Transition Unbilled @ 12/31/05	84.075	442505	0.741	
14	Total Unbilled Revenues	3.470			\$ 1.857
15	Total Actual 2005 Transition Revenues	4,367.434	2.677		\$ 116.916

Commonwealth Electric Company
Summary of Transition Charge - Fixed Component
\$ in Millions

Year	Commonwealth Electric Company		Residual Value Credit		Net Fixed Component
	Pre-Tax Return on Generation Related Assets	Amortization of Generation Related Assets	Pre-Tax Return on Commonwealth Generation Recovery/(Proceeds)	Amortization of Commonwealth Generation Recovery/(Proceeds)	
	Col. B	Col. C	Col. D	Col. E	Col. F
2005	\$ 0.012	\$ 0.026	\$ 0.005	\$ 0.019	\$ 0.062
2006	-	-	-	-	-
2007	-	-	-	-	-
2008	-	-	-	-	-
2009	-	-	-	-	-

Note: Amounts per D.T.E. 03-118/04-114 (Settlement), Exhibit COM-CLV-2A.

Col. F equals Sum of Col. B through Col. E.

2005 includes January to February only; post February 2005 eliminated due to Securitization.

Commonwealth Electric Company

Summary of Transition Charge - Variable Component

\$ in Millions

Year	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Power Contract Buyouts	Revenue Credits & Damages, Costs, or net Recoveries	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2005	118.415	90.482	27.933	(0.152)	47.977	(1.546)	0.275	74.486
2006	102.482	42.362	60.120	-	68.970	0.394	1.546	131.030
2007	90.819	37.061	53.758	-	64.209	-	(0.394)	117.573
2008	91.984	39.305	52.679	-	62.277	-	-	114.956
2009	83.120	40.301	42.819	-	60.180	-	-	102.999
2010	84.677	42.214	42.463	-	58.090	-	-	100.553
2011	85.555	43.852	41.703	-	55.970	-	-	97.673
2012	86.385	45.183	41.202	-	53.681	-	-	94.883
2013	87.535	46.898	40.637	-	8.886	-	-	49.523
2014	90.149	48.329	41.820	-	-	-	-	41.820
2015	90.636	49.678	40.958	-	-	-	-	40.958
2016	36.673	15.745	20.928	-	-	-	-	20.928
2017	8.924	4.456	4.468	-	-	-	-	4.468
2018	8.955	4.643	4.312	-	-	-	-	4.312
2019	8.989	4.837	4.152	-	-	-	-	4.152
2020	9.024	5.038	3.986	-	-	-	-	3.986
2021	9.422	5.245	4.177	-	-	-	-	4.177
2022	7.963	5.459	2.504	-	-	-	-	2.504
2023	2.654	1.899	0.755	-	-	-	-	0.755

Legend:

Col. B: Page 6, Col. S.
Col. C: Page 7, Col. T.
Col. D: Col. B - Col. C (see also Page 8, Col. T).
Col. E: Comel's share of Seabrook Power Contract Buyout Adjustment
Col. F: Exhibit COM-CLV-2 (Supp), Page 1, Col. L.
Col. G: Exhibit COM-HCL-5, Page 1, Col. E.
Col. H: Reversal of Prior Year Col. H.
Col. I: Col. D + Col. E + Col. F + Col. G + Col. H

Commonwealth Electric Company Summary of Transition Charge - Other Adjustments \$ in Millions

Year	Mitigation Incentive										Total Other Adjustments
	EIS Return on Investment Adjustment	Mitigation Incentive Adjustment	Other Adjustment	Deferral Recovery	Hydro Quebec Transmission	Fixed Component	Lowell Cogen. Buyout	Pilgrim Contract Buyout	Seabrook Buydown	Seabrook Buyout	
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2005	-	5.877	0.050	(136.128)	0.011	0.038	0.070	0.119	0.081	0.030	(129.853)
2006	-	-	-	-	0.012	-	-	-	-	-	0.012
2007	-	-	-	-	0.012	-	-	-	-	-	0.012
2008	-	-	-	-	0.012	-	-	-	-	-	0.012
2009	-	-	-	-	0.012	-	-	-	-	-	0.012
2010	-	-	-	-	0.012	-	-	-	-	-	0.012
2011	-	-	-	-	0.012	-	-	-	-	-	0.012
2012	-	-	-	-	0.012	-	-	-	-	-	0.012
2013	-	-	-	-	0.012	-	-	-	-	-	0.012
2014	-	-	-	-	0.012	-	-	-	-	-	0.012
2015	-	-	-	-	0.012	-	-	-	-	-	0.012
2016	-	-	-	-	0.012	-	-	-	-	-	0.012
2017	-	-	-	-	0.012	-	-	-	-	-	0.012
2018	-	-	-	-	0.012	-	-	-	-	-	0.012
2019	-	-	-	-	0.012	-	-	-	-	-	0.012
2020	-	-	-	-	0.012	-	-	-	-	-	0.012
2021	-	-	-	-	0.012	-	-	-	-	-	0.012

Col. C: 2005 NPV of 4 percent of NEA (\$3.616m from DTE 04-85,GOL-4(Compliance)), Masspower (\$.479m from DTE 04-61 RR-DTE-1(j) GOL-4 (Update2)) and Dartmouth (\$.660m from DTE 04-78 RR-AG-1(f) GOL-4) Buyout Savings and savings from Securitization of Deferrals (\$.913m from DTE 04-70 GOL -4) and the 4 percent of customer savings attributed to the sale of Cannon Street Station (COM-CLV-2, page 1, Col C*4%), plus 4% of Seabrook Buyout Adjustment (page 4, column E)

Col. D: 2005 adjustment per DTE 04-60 Altresco-Pittsfield Order Page 26 footnote 9.

Col. E: Deferral Buyout component of Securitization.

Col. F: Equals 4 percent of Page 6, Col. Q.

Cols.G to K: 2005 includes Jan to Feb only; post February 2005 eliminated due to Securitization.

Commonwealth Electric Company
Power Contract Obligations
Annual Obligations in Millions of Dollars

Year	Dartmouth Power	Altresco- Pittsfield	NEA 1 Bellingham (25MW)	NEA 2 Bellingham (21MW)	Mass- Power 1	Mass- Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Yankee Atomic	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P	Col. Q	Col. R	Col. S
Jan - Feb	\$ 6.471	\$ 0.835	\$ 0.251	\$ 0.093	\$ 4.153	\$ 4.291	\$ 0.190	\$ 0.116	\$ 1.668	\$ 0.114	\$ -	\$ 5.026	\$ 0.529	\$ 0.058	\$ 0.265	\$ (0.043)	\$ 0.228	\$ 24.245
Mar - Dec	<u>3.157</u>	<u>4.175</u>	<u>15.958</u>	<u>27.704</u>	<u>1.470</u>	<u>0.277</u>	<u>0.495</u>	<u>0.376</u>	<u>6.486</u>	<u>0.387</u>	<u>-</u>	<u>28.654</u>	<u>2.892</u>	<u>0.225</u>	<u>1.015</u>	<u>(0.235)</u>	<u>1.133</u>	<u>94.170</u>
2005	\$ 9.629	\$ 5.010	\$ 16.208	\$ 27.797	\$ 5.623	\$ 4.568	\$ 0.685	\$ 0.492	\$ 8.154	\$ 0.501	\$ -	\$ 33.679	\$ 3.421	\$ 0.283	\$ 1.280	\$ (0.278)	\$ 1.361	\$118.415
2006	-	15.030	11.165	25.925	-	-	0.632	0.371	7.963	0.312	-	33.748	4.350	0.153	1.491	(0.300)	1.642	102.482
2007	-	10.020	10.559	25.048	-	-	0.632	0.371	7.963	0.312	-	29.977	4.350	0.086	1.475	(0.300)	0.326	90.819
2008	-	10.020	10.902	25.886	-	-	0.632	0.371	7.963	0.312	-	29.977	4.350	0.088	1.461	(0.300)	0.322	91.984
2009	-	-	11.236	26.719	-	-	0.632	0.371	7.963	0.312	-	29.977	4.350	0.091	1.447	(0.300)	0.322	83.120
2010	-	-	11.738	27.784	-	-	0.632	0.371	7.963	0.312	-	29.977	4.350	0.094	1.434	(0.300)	0.322	84.677
2011	-	-	12.194	28.811	-	-	0.632	0.371	7.963	0.312	-	29.977	4.078	0.096	1.421	(0.300)	-	85.555
2012	-	-	12.551	29.293	-	-	0.632	0.371	7.963	0.312	-	29.977	4.078	0.099	1.409	(0.300)	-	86.385
2013	-	-	13.061	30.275	-	-	0.422	0.247	7.963	0.312	-	29.977	4.078	0.102	1.398	(0.300)	-	87.535
2014	-	-	13.802	33.102	-	-	-	-	7.963	0.032	-	29.977	4.078	0.104	1.391	(0.300)	-	90.149
2015	-	-	14.082	33.337	-	-	-	-	7.963	-	-	29.977	4.078	0.107	1.392	(0.300)	-	90.636
2016	-	-	9.466	18.370	-	-	-	-	7.963	-	-	-	-	0.111	1.063	(0.300)	-	36.673
2017	-	-	-	-	-	-	-	-	7.963	-	-	-	-	0.114	1.147	(0.300)	-	8.924
2018	-	-	-	-	-	-	-	-	7.963	-	-	-	-	0.117	1.175	(0.300)	-	8.955
2019	-	-	-	-	-	-	-	-	7.963	-	-	-	-	0.121	1.205	(0.300)	-	8.989
2020	-	-	-	-	-	-	-	-	7.963	-	-	-	-	0.125	1.236	(0.300)	-	9.024
2021	-	-	-	-	-	-	-	-	7.963	-	-	-	-	0.129	1.630	(0.300)	-	9.422
2022	-	-	-	-	-	-	-	-	7.963	-	-	-	-	-	-	-	-	7.963
2023	-	-	-	-	-	-	-	-	2.654	-	-	-	-	-	-	-	-	2.654

Note: 2005 (Jan to Feb) per Exhibit COM-CLV-4, Page 3.
2005 (Mar to Dec) - 10 months actual.
Post 2005 per Company forecast.

Commonwealth Electric Company
Power Contract Obligations
Annual Market in Millions of Dollars

Year	Dartmouth Power	Altresco- Pittsfield	NEA 1 Bellingham (25MW)	NEA 2 Bellingham (21MW)	Mass- Power 1	Mass- Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Yankee Atomic	Other Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P	Col. Q	Col. R	Col. S	Col. T
Jan - Feb	\$ 2.031	\$ -	\$ 1.959	\$ 1.637	\$ 1.743	\$ 1.743	\$ 0.114	\$ 0.072	\$ 0.919	\$ 0.071	\$ -	\$ 3.158	\$ 0.983	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 14.430
Mar - Dec	3.619	-	14.896	11.963	1.108	0.083	0.429	0.348	5.078	0.357	-	26.384	11.787	-	-	-	-	-	76.052
2005	\$ 5.650	\$ -	\$ 16.855	\$ 13.600	\$ 2.851	\$ 1.826	\$ 0.543	\$ 0.420	\$ 5.998	\$ 0.428	\$ -	\$ 29.541	\$ 12.770	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 90.482
2006	-	-	8.417	7.073	-	-	0.284	0.166	3.334	0.140	-	15.473	7.475	-	-	-	-	-	42.362
2007	-	-	7.872	6.615	-	-	0.265	0.156	3.118	0.131	-	14.472	6.991	-	-	-	-	(2.559)	37.061
2008	-	-	8.123	6.825	-	-	0.274	0.161	3.217	0.135	-	14.932	7.214	-	-	-	-	(1.576)	39.305
2009	-	-	8.366	7.029	-	-	0.282	0.165	3.313	0.139	-	15.378	7.429	-	-	-	-	(1.800)	40.301
2010	-	-	8.761	7.361	-	-	0.295	0.173	3.470	0.146	-	16.104	7.780	-	-	-	-	(1.876)	42.214
2011	-	-	9.110	7.655	-	-	0.307	0.180	3.608	0.151	-	16.747	8.091	-	-	-	-	(1.997)	43.852
2012	-	-	9.436	7.928	-	-	0.318	0.187	3.737	0.157	-	17.345	8.379	-	-	-	-	(2.304)	45.183
2013	-	-	9.855	8.281	-	-	0.221	0.130	3.903	0.164	-	18.116	8.752	-	-	-	-	(2.524)	46.898
2014	-	-	10.229	8.595	-	-	-	-	4.051	0.017	-	18.804	9.084	-	-	-	-	(2.451)	48.329
2015	-	-	10.509	8.830	-	-	-	-	4.162	-	-	19.319	9.333	-	-	-	-	(2.475)	49.678
2016	-	-	7.736	6.500	-	-	-	-	4.334	-	-	-	-	-	-	-	-	(2.825)	15.745
2017	-	-	-	-	-	-	-	-	4.456	-	-	-	-	-	-	-	-	-	4.456
2018	-	-	-	-	-	-	-	-	4.643	-	-	-	-	-	-	-	-	-	4.643
2019	-	-	-	-	-	-	-	-	4.837	-	-	-	-	-	-	-	-	-	4.837
2020	-	-	-	-	-	-	-	-	5.038	-	-	-	-	-	-	-	-	-	5.038
2021	-	-	-	-	-	-	-	-	5.245	-	-	-	-	-	-	-	-	-	5.245
2022	-	-	-	-	-	-	-	-	5.459	-	-	-	-	-	-	-	-	-	5.459
2023	-	-	-	-	-	-	-	-	1.899	-	-	-	-	-	-	-	-	-	1.899

Note: 2005 (Jan to Feb) per Exhibit COM-CLV-4, Page 2.
2005 (Mar to Dec) - 10 months actual.
Post 2005 per Company forecasts.

Commonwealth Electric Company
Power Contract Obligations
Annual Above Market in Millions of Dollars

Year	Dartmouth Power	Altresco- Pittsfield	NEA 1 Bellingham (25MW)	NEA 2 Bellingham (21MW)	Mass- Power 1	Mass- Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Yankee Atomic	Other Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P	Col. Q	Col. R	Col. S	Col. T
Jan - Feb	\$ 4.440	\$ 0.835	\$ (1.709)	\$ (1.544)	\$ 2.411	\$ 2.548	\$ 0.077	\$ 0.044	\$ 0.749	\$ 0.043	\$ -	\$ 1.868	\$ (0.454)	\$ 0.058	\$ 0.265	\$ (0.043)	\$ 0.228	\$ -	\$ 9.815
Mar - Dec	(0.461)	4.175	1.061	15.741	0.362	0.194	0.066	0.028	1.408	0.030	-	2.270	(8.895)	0.225	1.015	(0.235)	1.133	-	18.118
2005	\$ 3.979	\$ 5.010	\$ (0.647)	\$ 14.197	\$ 2.773	\$ 2.743	\$ 0.142	\$ 0.072	\$ 2.156	\$ 0.073	\$ -	\$ 4.138	\$ (9.349)	\$ 0.283	\$ 1.280	\$ (0.278)	\$ 1.361	\$ -	\$ 27.933
2006	-	15.030	2.748	18.852	-	-	0.348	0.205	4.629	0.172	-	18.275	(3.125)	0.153	1.491	(0.300)	1.642	-	60.120
2007	-	10.020	2.687	18.433	-	-	0.367	0.215	4.845	0.181	-	15.505	(2.641)	0.086	1.475	(0.300)	0.326	2.559	53.758
2008	-	10.020	2.779	19.061	-	-	0.358	0.210	4.746	0.177	-	15.045	(2.864)	0.088	1.461	(0.300)	0.322	1.576	52.679
2009	-	-	2.870	19.690	-	-	0.350	0.206	4.650	0.173	-	14.599	(3.079)	0.091	1.447	(0.300)	0.322	1.800	42.819
2010	-	-	2.977	20.423	-	-	0.337	0.198	4.493	0.166	-	13.873	(3.430)	0.094	1.434	(0.300)	0.322	1.876	42.463
2011	-	-	3.084	21.156	-	-	0.325	0.191	4.355	0.161	-	13.230	(4.013)	0.096	1.421	(0.300)	-	1.997	41.703
2012	-	-	3.115	21.365	-	-	0.314	0.184	4.226	0.155	-	12.632	(4.301)	0.099	1.409	(0.300)	-	2.304	41.202
2013	-	-	3.206	21.994	-	-	0.201	0.117	4.060	0.148	-	11.861	(4.674)	0.102	1.398	(0.300)	-	2.524	40.637
2014	-	-	3.573	24.507	-	-	-	-	3.912	0.015	-	11.173	(5.006)	0.104	1.391	(0.300)	-	2.451	41.820
2015	-	-	3.573	24.507	-	-	-	-	3.801	-	-	10.658	(5.255)	0.107	1.392	(0.300)	-	2.475	40.958
2016	-	-	1.730	11.870	-	-	-	-	3.629	-	-	-	-	0.111	1.063	(0.300)	-	2.825	20.928
2017	-	-	-	-	-	-	-	-	3.507	-	-	-	-	0.114	1.147	(0.300)	-	-	4.468
2018	-	-	-	-	-	-	-	-	3.320	-	-	-	-	0.117	1.175	(0.300)	-	-	4.312
2019	-	-	-	-	-	-	-	-	3.126	-	-	-	-	0.121	1.205	(0.300)	-	-	4.152
2020	-	-	-	-	-	-	-	-	2.925	-	-	-	-	0.125	1.236	(0.300)	-	-	3.986
2021	-	-	-	-	-	-	-	-	2.718	-	-	-	-	0.129	1.630	(0.300)	-	-	4.177
2022	-	-	-	-	-	-	-	-	2.504	-	-	-	-	-	-	-	-	-	2.504
2023	-	-	-	-	-	-	-	-	0.755	-	-	-	-	-	-	-	-	-	0.755

Note: Annual Above Market = Annual Obligation (page 6) minus Annual Market (page 7).

Commonwealth Electric Company
Revenue Credits & Damages, Costs, or Net Recoveries from Claims
\$ in Millions

Year	Payment in Lieu of Property Tax	Claims and Recoveries	Sales of Property	Future Use	Future Use	DOE/SNF Litigation	Securitization Payment	Cannon St. Emission Credits	Standard Offer Revenues	Securitization Transaction Cost True-up	Other PPA Transaction Costs	Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2005	\$ 1.430	\$ (0.239)	\$ (5.083)	\$ -	\$ -	\$ 0.077	\$ 57.593	\$ (0.006)	\$ (6.236)	\$ (0.034)	\$ 0.474	\$ 47.977
2006	1.265	-	-	-	-	-	67.705	-	-	-	-	68.970
2007	0.660	-	-	-	-	-	63.549	-	-	-	-	64.209
2008	0.110	-	-	-	-	-	62.167	-	-	-	-	62.277
2009	0.110	-	-	-	-	-	60.070	-	-	-	-	60.180
2010	0.110	-	-	-	-	-	57.980	-	-	-	-	58.090
2011	0.110	-	-	-	-	-	55.860	-	-	-	-	55.970
2012	0.055	-	-	-	-	-	53.626	-	-	-	-	53.681
2013	-	-	-	-	-	-	8.886	-	-	-	-	8.886

Notes: Col. A per Page 2.
Col. B per Page 3.
Col. C per Page 4.
Col. F per Page 5.
Col. G per Page 6.
Col. H per Page 7.
Col. I per Page 8.
Col. J per Page 9.
Col. K per Page 10.
Col. L equals Sum of Col. A thru Col. K.

**Commonwealth Electric Company
Payments in Lieu of Property Taxes
\$ in Millions**

Year	Actual/Required Payment to Town	Entergy Direct Payments	Net BECo Payments	Contract Customer Share
	Col. A	Col. B	Col. C	Col. D
2005	\$ 13.000	\$ -	\$ 13.000	\$ 1.430
2006	11.500	-	11.500	1.265
2007	6.000	-	6.000	0.660
2008	1.000	-	1.000	0.110
2009	1.000	-	1.000	0.110
2010	1.000	-	1.000	0.110
2011	1.000	-	1.000	0.110
2012	0.500	-	0.500	0.055

Notes: Col. A Actual property tax payment for 2005, future years per tax agreement with Town of Plymouth Approved in D.T.E. 98-53.

Col. B equals Actual Payments received from Entergy, if any.

Col. C equals Col. A - Col. B.

Col. D equals 11% of Col. C.

Commonwealth Electric Company
Claims and Recoveries
\$ in Millions

2005

<u>Line</u>	<u>NEIL Insurance Credit Refund:</u>	
1	Entergy NEIL Credit for Pilgrim	\$ (2.557)
2	Percentage paid to BECo per Pilgrim P & S	<u>85%</u>
3	BECo Share of Pilgrim NEIL Credit to be received by 12/31	\$ (2.173)
4	11 % Contract Customer Share	\$ (0.239)
5	<u>Maxey Flats LLC Expenses:</u>	
6	2005 Maxey Flats Payment	\$ -
7	Less: Payment received from American Ecology	<u>-</u>
8	Net Maxey Flats Payments	\$ -
9	11 % Contract Purchaser Share	\$ -
10	Total Pilgrim Adjustments	<u>\$ (0.239)</u>

Commonwealth Electric Light Company
Property Sales-Sale of Cannon Street Facility
\$ in Millions

Line		Total	Reference
1	Total Sale Proceeds	\$12.023	
2			
3	Closing Costs:		
4	Broker Commission	(\$1.082)	
5	Deed Stamps	(0.055)	
6	Recording/Escrow Fees/Other	(0.002)	
7	Total	(1.139)	Sum of Lines 4 through 6
8			
9	Net Sale Proceeds	\$10.885	Line 1 minus Line 7
10			
11	Transaction Costs:		
12	Make Ready Cost (Stack Removal & Masonry)	(\$0.403)	
13	Other	(0.087)	
14	Total	(0.490)	Sum of Lines 12 and 13
15			
16	Net Sale Proceeds after Transaction Costs	\$10.394	Sum of Lines 9 and 14
17			
18	Post-Closing Construction Costs:		
19	Environmental Cost (Inner Slip & Remediation)	(\$1.500)	
20	Equipment Relocation (Oil Pump House & Capacitor Bank)	(0.800)	
21	Total	(2.300)	Sum of Lines 19 and 20
22			
23	Net Proceeds	\$8.094	Sum of Lines 16 and 21
24			
25			
26	<u>Ordinary Gain to Customers</u>		
27	Market Value on Facility Closing Date (12/18/1992)	\$2.680	
28			
29	Net Asset Value (12/18/1992):		
30	Gross Plant	\$1.723	
31	Accumulated Depreciation	(1.052)	
32	Net Plant	\$0.671	Sum of Lines 30 and 31
33			
34	Ordinary Gain to Customers	\$2.009	Line 27 minus Line 32
35			
36	<u>Ordinary Gain to NSTAR</u>		
37	Market Value Prior to Sale Bid Receipt (11/30/2005)	\$5.692	
38			
39	Market Value on Facility Closing Date (12/18/1992)	\$2.680	Line 27
40			
41	Ordinary Gain to NSTAR	\$3.012	Line 37 minus Line 39
42			
43	<u>Extraordinary Gain</u>		
44	Net Proceeds	\$8.094	Line 23
45			
46	Ordinary Gains (11/30/2005):		
47	Customers	\$2.009	Line 34
48	NSTAR	3.012	Line 41
49	Total	\$5.020	Sum of Lines 47 and 48
50			
51	Extraordinary Gain	\$3.074	Line 44 minus Line 49
52			
53	Total Estimated Customer Gain on Property Sold	5.083	Sum of Lines 34 and 51
54	Total NSTAR Gain	3.012	Line 41
55		\$8.094	Sum of Lines 53 and 54

Commonwealth Electric Company

**Department of Energy (DOE)/Spent Nuclear Fuel (SNF) Litigation Expense
\$ in Millions**

	Invoice Date	Vendor	Invoice Amount	Cumulative Invoice Amount	Legal Fees	Disburse- ments	Fees & Disburse- ments	Litigation Share @ 30.42%
1	23-Dec-04	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.039	\$ 0.039	\$ 121,999	\$ 6,794	\$ 128,793	\$ 39,179
2	23-Dec-04	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.002	\$ 0.041	\$ -	\$ 4,963	\$ 4,963	\$ 1,510
3	31-Jan-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.052	\$ 0.093	\$ 164,706	\$ 7,113	\$ 171,819	\$ 52,267
4	28-Feb-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.056	\$ 0.149	\$ 53,830	\$ 2,033	\$ 55,863	
5	28-Feb-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.007	\$ 0.156	\$ -	\$ 7,189	\$ 7,189	
6	29-Mar-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.055	\$ 0.211	\$ 51,950	\$ 2,737	\$ 54,687	
7	29-Mar-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.016	\$ 0.226	\$ -	\$ 15,601	\$ 15,601	
8	29-Apr-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.038	\$ 0.265	\$ 36,823	\$ 1,603	\$ 38,426	
9	29-Apr-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.009	\$ 0.273	\$ -	\$ 8,691	\$ 8,691	
10	24-Jun-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.001	\$ 0.275	\$ -	\$ 1,402	\$ 1,402	
11	28-Jun-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.038	\$ 0.313	\$ 35,830	\$ 2,301	\$ 38,131	
12	28-Jun-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.029	\$ 0.342	\$ 27,517	\$ 1,836	\$ 29,353	
13	21-Jul-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.004	\$ 0.347	\$ -	\$ 4,396	\$ 4,396	
14	21-Jul-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.031	\$ 0.378	\$ 29,361	\$ 1,814	\$ 31,176	
15	31-Aug-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.031	\$ 0.409	\$ 26,458	\$ 4,382	\$ 30,840	
16	26-Sep-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.060	\$ 0.468	\$ 57,490	\$ 2,190	\$ 59,680	
17	26-Sep-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.001	\$ 0.470	\$ -	\$ 1,218	\$ 1,218	
18	31-Oct-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.076	\$ 0.545	\$ 67,177	\$ 8,661	\$ 75,837	
19	31-Oct-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.022	\$ 0.567	\$ -	\$ 21,641	\$ 21,641	
20	22-Nov-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.055	\$ 0.622	\$ 50,047	\$ 4,824	\$ 54,870	
21	22-Nov-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.015	\$ 0.637	\$ -	\$ 15,259	\$ 15,259	
22	7-Dec-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.054	\$ 0.692	\$ 49,069	\$ 5,248	\$ 54,317	
23	7-Dec-05	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.010	\$ 0.702	\$ -	\$ 10,132	\$ 10,132	
24								
25	Subtotal	Dickstein Shapiro Morin & Oshinsky, LLP	\$ 0.702					
26								
27	19-Sep-05	Navigant Consulting	\$ 0.000	\$ 0.702	\$ 420	\$ -	\$ 420	
28	22-Nov-05	Navigant Consulting	\$ 0.001	\$ 0.703	\$ 1,002	\$ -	\$ 1,002	
29								
30	Subtotal	Navigant Consulting	\$ 0.001					
31								
32	DOE/SNF Litigation Expenses Incurred in 2005		\$ 0.703					
33	11% Contract Customer Share		\$ 0.077					

**Commonwealth Electric Company
Securitization
\$ in Millions**

Year	Beginning Collection & Reserve Account Balance	Plus: Estimated Securitization Collections	Less: RRB Principal Payments	Less: RRB Interest Payments	Less: Ongoing Costs	Less: Overcollat- eralization	Plus: Estimated Interest Earned	Ending Collection & Reserve Account Balance	Gross-Up of Securitization Collections Charge-offs @ 0.53%	Estimated Variable Component Collections
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
2005	\$ -	\$ 57.662	\$ (20.000)	\$ (8.795)	\$(0.136)	\$ (0.128)	\$ 0.378	\$ 28.982	\$ 0.309	\$ 57.593
2006	28.982	67.541	(56.458)	(15.111)	(0.294)	(0.256)	0.100	24.505	0.264	67.705
2007	24.505	63.400	(50.000)	(13.194)	(0.294)	(0.256)	0.100	24.262	0.249	63.549
2008	24.262	62.024	(51.337)	(11.283)	(0.294)	(0.256)	0.100	23.217	0.243	62.167
2009	23.217	59.935	(51.113)	(9.235)	(0.294)	(0.256)	0.100	22.354	0.235	60.070
2010	22.354	57.851	(51.172)	(7.123)	(0.294)	(0.256)	0.100	21.459	0.229	57.980
2011	21.459	55.741	(51.155)	(5.011)	(0.294)	(0.256)	0.100	20.586	0.219	55.860
2012	20.586	53.516	(51.166)	(2.836)	(0.294)	(0.256)	0.100	19.650	0.210	53.626
2013	19.650	8.876	(26.599)	(0.585)	(0.147)	(0.128)	0.025	1.092	0.035	8.886
Total		\$ 486.546	\$ (409.000)	\$ (73.171)	\$ (2.340)	\$ (2.045)	\$ 1.103	\$ 1.092	\$ 1.993	\$ 487.436

Col. A Col. H prior year

Col. B RTC collections estimate

Col. C RRB principal payments made on March 15th and September 15th.

Col. D RRB interest payments made on March 15th and September 15th.

Col. E Attachment 2 of Issuance Advice Letter dated 2/18/05

Col. F Attachment 2 of Issuance Advice Letter dated 2/18/06

Col. G Estimated interest earned

Col. H Sum of Cols. A to G

Col. I (Col. B / (1 - .0039)) - Col. B

Col. J Col. B - Col. G + Col. I

**Commonwealth Electric Company
Cannon Street Emission Credit
\$ in Millions**

<u>Line</u>	<u>Description</u>	<u>2005</u>
1	Total SO2 Emission Credit Revenue	<u>\$ (0.006)</u>

Commonwealth Electric Company
Post Standard Offer Period Revenues
\$ in Millions

Line	Description	Account	Actual Mar-05	Actual Apr-05	Actual May-05	Actual Jun-05	Actual Jul-05	Actual Aug-05	Actual Sep-05	Actual Oct-05	Actual Nov-05	Dec-05	Total
1	Standard Offer Revenues												
2	Residential	440170	\$ 3.720	\$ (0.036)	\$ (0.002)	\$ (0.002)	\$ 0.001	\$ (0.000)	\$ (0.000)	\$ (0.000)	\$ 0.000	\$ 0.000	\$ 3.680
3	Commercial	442450	2.326	0.007	(0.003)	(0.000)	(0.006)	(0.000)	(0.000)	0.000	(0.001)	(0.000)	2.322
4	Industrial	442460	0.229	(0.001)	-	-	-	-	-	-	-	-	0.229
5	Street Lighting	444070	0.005	-	-	-	-	-	-	-	-	-	0.005
6	Total Standard Offer Revenues		<u>\$ 6.280</u>	<u>\$ (0.030)</u>	<u>\$ (0.006)</u>	<u>\$ (0.002)</u>	<u>\$ (0.005)</u>	<u>\$ (0.001)</u>	<u>\$ (0.000)</u>	<u>\$ (0.000)</u>	<u>\$ (0.000)</u>	<u>\$ 0.000</u>	<u>\$ 6.236</u>

**Commonwealth Electric Company
CEC Funding, LLC
Securitized Rate Reduction Bonds
Transaction Costs Reconciliation
\$ in Millions**

Line #		CEC Funding per Iss Adv Ltr Attachment 1 (A)	CEC Funding Actual Costs	Difference
1	Transaction Costs of Issuance			
2	Underwriting Spread	\$ 1.730	\$ 1.730	\$ -
3	Financial Advisory Fee	-	-	-
4	Rating Agency Fees	0.386	0.388	0.002
5	Accounting Fees	0.061	0.088	0.027
6	SEC Registration Fee	0.048	0.052	0.004
7	DTE Filing Fee	0.062	0.062	0.000
8	Printing and Marketing Expenses	0.061	0.075	0.015
9	Trustee Fees and Counsel	0.021	0.050	0.029
10	Company Legal Fees and Expenses	1.213	0.754	(0.459)
11	Underwriters' Legal Fees and Expenses	-	0.168	0.168
12	Bond Counsel Legal Fees and Expenses	-	0.206	0.206
13	MassDevelopment/HEFA Fees (Agency Fees)	0.121	0.121	0.000
14	MassDevelopment/HEFA Fees (Agency Expenses)	-	0.001	0.001
15	Servicing Set-Up Costs	-	-	-
16	Lender Consent Fees	0.210	0.223	0.012
17	Day Loan	0.011	0.011	(0.000)
18	SPE Set-Up Costs	-	-	-
19	Miscellaneous Costs	0.058	0.018	(0.039)
20	Transaction Costs of Issuance (excluding original issue discount)	\$ 3.982	\$ 3.948	\$ (0.034)
21				
22	Original Issue Discount	0.050	0.050	-
23				
24	Total Transaction Costs of Issuance (Line 20 + Line 22)	\$ 4.032	\$ 3.998	\$ (0.034)

(A) per Attachment 1 of Issuance Advice Letter dated 2/18/05

Commonwealth Electric Company Other PPA Buyout Transaction Costs \$ in Millions						
<u>Line #</u>	<u>Vendor</u>	<u>Amount</u>	<u>Allocated to Securitization</u>	<u>Other PPA Amount</u>		
1	Concentric Energy Advisors	\$ 0.671	\$ 0.400	\$ 0.270		
2	Keegan Werlin	\$ 0.637	\$ 0.377	\$ 0.260		
3	Ropes & Gray	\$ 0.065	\$ 0.039	\$ 0.026		
4	Total Other Transaction Costs	<u>\$ 1.373</u>	<u>\$ 0.816</u>	<u>\$ 0.556</u>		
5						
6		<u>BECo.</u>	<u>COM</u>	<u>CAM</u>	<u>Total</u>	
7	Other PPA Transaction Costs	\$ 0.056	\$ 0.474	\$ 0.027	\$ 0.556	

Commonwealth Electric Company
2005 Retail Transmission Cost
\$ in Millions

Line	Description	Tariff	Account	Dec-04	Actual Jan-05	Actual Feb-05	Actual Mar-05	Actual Apr-05	Actual May-05	Actual Jun-05	Actual Jul-05	Actual Aug-05	Actual Sep-05	Actual Oct-05	Actual Nov-05	Actual Dec-05	Total
Regional Transmission Costs																	
1	Retail RNS Cost	ISO Schedule 9	565590		\$ 1.234	\$ 1.158	\$ 1.058	\$ 1.056	\$ 1.300	\$ 1.322	\$ 1.424	\$ 1.474	\$ 1.638	\$ 1.498	\$ 1.366	\$ 1.058	\$ 15.586
2	Regional Ancillary Services																
3	Retail Schedule & Dispatch Cost	ISO Schedule 1	561140		0.099	0.115	0.112	0.102	0.101	0.088	0.095	0.131	0.153	0.152	0.126	0.107	1.380
4	Retail Congestion Management Cost	Note A	565210		0.169	0.139	0.099	(0.340)	(0.003)	-	-	0.645	0.396	0.125	-	(0.554)	0.675
5	System Restoration & Planning Cost	ISO Schedule 16	565060		0.024	0.024	0.025	0.025	0.025	0.025	0.049	0.022	0.024	0.025	0.024	0.025	0.317
6	Load Dispatching (REMVEC II)	ISO Schedule 1	561110		-	-	-	-	-	0.008	0.008	0.008	0.008	0.009	0.008	0.008	0.058
7	VAR Support Cost	ISO Schedule 2			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total Regional Transmission Costs				1.526	1.436	1.295	0.842	1.423	1.443	1.576	2.281	2.218	1.810	1.524	0.644	18.018
Local Transmission Costs																	
9	Determination of Local Network Service (LNS) Costs																
11	Monthly Transmission Revenue Requirement	ISO Schedule 21 *			\$ 0.698	\$ 0.806	\$ 0.806	\$ 0.806	\$ 0.806	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 8.518
12	Monthly Dispatch Center Revenue Requirement	Note B	566710		0.009	0.008	0.012	0.009	0.008	-	-	-	-	-	-	-	0.047
13	Schedule 1 Revenues Received	ISO Schedule 1	456920		(0.007)	(0.009)	(0.008)	(0.008)	(0.008)								(0.039)
14	LNS Revenue Requirement				\$ 0.700	\$ 0.805	\$ 0.810	\$ 0.808	\$ 0.807	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 8.526
15	Retail Load Ratio				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
16	Retail LNS Revenue Requirement				\$ 0.700	\$ 0.805	\$ 0.810	\$ 0.808	\$ 0.807	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 0.657	\$ 8.526
17																	
18	Total Transmission Costs				\$ 2.226	\$ 2.241	\$ 2.105	\$ 1.650	\$ 2.230	\$ 2.099	\$ 2.232	\$ 2.937	\$ 2.875	\$ 2.466	\$ 2.180	\$ 1.301	\$ 26.543
Transmission Revenues Detail																	
20	Residential		440140		\$ 1.089	\$ 0.957	\$ 0.888	\$ 0.742	\$ 0.630	\$ 0.868	\$ 1.012	\$ 1.225	\$ 1.088	\$ 0.823	\$ 0.756	\$ 0.850	\$ 10.928
21	Commercial		442380		0.838	0.721	0.655	0.647	0.576	0.783	0.835	0.874	0.866	0.780	0.665	0.627	8.867
22	Industrial		442400		0.149	0.164	0.113	0.341	0.138	0.142	0.193	0.138	0.161	0.167	0.133	0.106	1.945
23	Street Lighting		444050		0.006	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.063
24	Transmission Revenues				\$ 2.081	\$ 1.847	\$ 1.661	\$ 1.736	\$ 1.349	\$ 1.798	\$ 2.046	\$ 2.242	\$ 2.120	\$ 1.775	\$ 1.559	\$ 1.589	\$ 21.803
25	Retail Transmission Deferral (Over)/Under Collection				\$ 0.145	\$ 0.394	\$ 0.443	\$ (0.086)	\$ 0.881	\$ 0.301	\$ 0.187	\$ 0.695	\$ 0.755	\$ 0.691	\$ 0.622	\$ (0.288)	\$ 4.740
26	Interest on Transmission Deferral Balance				(0.003)	(0.002)	(0.001)	(0.001)	(0.000)	0.001	0.002	0.003	0.004	0.005	0.007	0.007	0.022
27	Transmission Deferral (Over)/Under Ending Balance		182874	\$ (1.346)	\$ (1.204)	\$ (0.811)	\$ (0.369)	\$ (0.456)	\$ 0.425	\$ 0.727	\$ 0.916	\$ 1.613	\$ 2.373	\$ 3.069	\$ 3.697	\$ 3.416	
28	Annual Interest Rate				2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	

Note A: ISO Schedule 19 (SCR) and Market Rule 1 (RMR)

Note B: Schedule 1 of ISO Schedule 21

* Amount includes revenue credit of wholesale customer revenues

[illegible]

[illegible]

**Commonwealth Electric Company
Monthly Default Service Adder Deferral
\$ in Millions**

[illegible]

[illegible]